**BEFORE**
**THE PUBLIC SERVICE COMMISSION OF**
**SOUTH CAROLINA**

**DOCKET NOS. 2019-224-E and 2019-225-E**

| | |
|---|---|
| In the Matter of: | ) |
| | ) |
| South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC | ) ) ) ) ) ) |

# DIRECT TESTIMONY OF ARNE OLSON

## ON BEHALF OF

## THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

**Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS AFFILIATION.**

**A:** My name is Arne Olson. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3"), located at 44 Montgomery Street, Suite 1500, San Francisco, California 94104, USA.

**Q2. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.**

**A:** I have over 25 years of experience in the energy industry, specializing in the areas of transmission planning, rate and tariff design, integrated resource planning and renewable energy planning – including renewable energy procurement, program design and transmission assessment, and energy policy analysis. I have consulted extensively for utilities, government agencies, transmission system operators, renewable energy project developers, transmission project developers, and large consumers regarding renewable energy procurement and related transmission needs. I hold a Master of Science degree in Energy Management and Policy from the University of Pennsylvania and Bachelor of Science degree in Statistics and Mathematical Sciences from the University of Washington. I have previously been retained as an expert and have provided expert testimony in front of the California Energy Commission, the California Public Utilities Commission, the Alberta Utilities Commission, the Oregon Public Utilities Commission, the Georgia Public Service Commission, and the New Mexico Public Regulatory Commission. I have provided expert testimony to legislative committees in Washington and California and I recently spoke at a U.S. Federal Energy Regulatory Commission Technical Conference on Carbon Pricing by invitation of the Chair.

I have served as the lead investigator in developing integrated resource plans for utilities and state agencies across North America. Much of my resource planning work has focused on helping utilities analyze the impacts of higher penetrations of variable renewable resources on their operations and investment decisions. Some examples of current and past projects include:

- I am a co-author of the 2016 Report Number 6 of the Lawrence Berkeley National Laboratory's "Future Electric Utility Regulation Series," entitled "The Future of Integrated Resource Planning."
- I am currently leading a team that is supporting Nova Scotia Power's Integrated Resource Plan focusing on the recently established provincial goal of achieving net zero carbon emissions by 2050.
- I am currently leading a team that is evaluating the potential for regional transmission projects such as the “Atlantic Loop” to provide benefits to electric ratepayers in the Atlantic provinces of Canada.
- For the Sacramento Municipal Utilities District, I led the development of their 2018 IRP which considered scenarios and resource portfolios for meeting California's and SMUD's own aggressive renewables goals including 100% renewables by 2040.
- For Xcel Energy, I led an effort to support development of Northern States Power's 2018-19 IRP examining high renewable scenarios within the context of the company's stated goal of completely decarbonizing their electric resource portfolio by 2050.
- For a group of utilities in the Pacific Northwest, I led studies in 2017 and 2018 that examined scenarios achieving 50% renewables and up to 100% carbon reductions across the region, focusing on policy mechanisms to achieve the goals at least cost and

on the nature and quantity of complementary resources that are needed to maintain reliable electric service.

- I have led several studies of the means to ensure resource adequacy under high renewable power systems, including a 2019 study of the California system entitled "Long-Run Resource Adequacy under Deep Decarbonization Pathways Scenarios for California", funded by the Calpine Corporation, and a 2018 study entitled "Resource Adequacy in the Pacific Northwest" funded by a coalition of 13 publicly-owned and investor-owned utilities. I am also supporting the Northwest Power Pool's ongoing effort to develop a regional resource adequacy program in the Pacific Northwest.
- In 2018, I led a study of the value of partially- and fully-dispatchable solar and solar + storage power plants on the Tampa Electric Company (TECO) system. The study was funded by First Solar but it involved extensive participation by a wide range of TECO staff and included detailed TECO power system data. First Solar and TECO jointly received a "2018 Top Innovators" award from Public Utilities Fortnightly in conjunction with the study and TECO was selected as a finalist for a 2019 Platts Global Energy Award in the "Grid Edge" category.
- For a group comprising the five largest utilities in California (Los Angeles Department of Water and Power, Pacific Gas and Electric Company, Sacramento Municipal Utilities District, San Diego Gas & Electric Company, and Southern California Edison), I led a landmark 2014 study of the feasibility, cost implications and complementary measures for achieving 50% renewables by 2030.

- I have participated in several other E3 resource planning studies of achieving very high renewable penetrations for the Hawaiian Electric Company, the New York State Energy Research and Development Authority, and Arizona Public Service Company.
- I lead a team at E3 that supports the California Public Utilities Commission staff in developing a Reference System Plan for California and designing and implementing integrated resource planning standards for California load serving entities.
- A copy of my curriculum vitae is attached to my testimony as Exhibit AO-1.

**Q3. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO THIS COMMISSION?**

A: No, I have not.

**Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

**A:** My testimony describes and summarizes E3's technical review of Duke Energy's integrated resource plan ("IRP"), with specific emphasis on Duke's resource adequacy process. The full technical report (the "Report") is attached to my testimony as Exhibit AO-2.

**Q5. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

**A:** Through my technical review of the Duke IRP I find that due to flaws in Duke's assumptions, Duke's analysis and IRP significantly understate the ability of solar and storage resources to help meet Duke's projected energy and capacity needs. I find three main problems with Duke's analysis.

First, Duke did not model solar and storage in a manner that accounts for the synergies between them, which is necessary to accurately capture the capacity benefits of those resources on Duke's system. Because solar and storage were instead modeled sequentially – solar evaluated before storage was present to augment it, and with storage evaluated after the amount of solar to charge it was determined – their combined ability to reliably and cost-effectively provide capacity to meet load was obscured, and in fact limited. Duke's failure to use co-optimization of all potential generation technologies is the most significant and consequential flaw identified in the Report. This flaw makes it impossible for Duke to even consider the possibility that solar and storage together are the most cost-effective solution to capacity needs in the near term, a conclusion that many other utilities around the country have come to. Duke should be directed to conduct capacity expansion modeling using single-step optimization of all resources to provide an accurate evaluation of the cost and reliability impacts of those options to meet projected energy and capacity needs.

Second, Duke's calculation of Effective Load-Carrying Capability (ELCC) values utilized inaccurate methodologies and assumptions that significantly understate the effective capacity contribution of solar and of storage. Most significantly, as I will discuss below Duke fails to consider the diversity benefits that arise from adding solar and storage together. To remedy this omission, Duke should model the combined effects through the use of an ELCC "surface" – in effect, a table of ELCC values that vary as a function of the penetration of both solar and storage. Duke also used outdated demand response assumptions; made inappropriate assumptions regarding the amount of fixed-tilt solar that will be built in the future; and failed to model ELCC values that are dynamic with load levels.

Third, Duke's implementation of its planning reserve margin was flawed and skewed the results to understate solar's actual capacity value relative to firm resources such as natural gas generation. In particular, when evaluating the relative capacity contributions of competing resources to load, Duke assumed 100% availability of fossil fuel generation – thus excluding forced outages – while utilizing Effective Load Carrying Capability ("ELCC") for solar – a measure that includes such outages. This apples-to-oranges calculation inaccurately discounted solar's ability to meet projected energy and capacity needs. Duke should be directed to revise its methodology so that the capacity credit of solar and other resources is determined and presented on equal footing.

**Q6. DOES THE REPORT ALSO DESCRIBE IRP BEST PRACTICES?**

**A:** Yes, the Report also describes a number of IRP best practices, many of which have not been followed by Duke, including the following:

1. Incorporate climate policy and the impact of climate change.

   The realities of climate change are resulting in both technological and cost realities for electricity systems that must be incorporated in any IRP process.

2. Include renewable energy and energy storage as potential resources.

   Historical capacity expansion modeling methodologies struggle to incorporate the intermittent nature of renewables as well as the flexibility of energy storage systems. Current IRPs require renewables and energy storage to meet climate change policies and as such they must be included as potential resources and modeled appropriately.

3. Capacity need should be determined through loss of load probability (LOLP) modeling.

   Intermittent resources (renewables) as well as energy storage are not accounted for appropriately in standard installed capacity (ICAP) planning reserve margin (PRM) studies; more nuanced reliability metrics – such as an unforced capacity (UCAP) planning reserve margin – must be used that account for the outage rates of both renewables and thermal generation alike.

4. The IRP process should consider the benefits of demand side resources.

   Demand side resources, like the ability to curtail or shift load, can provide significant value when trying to meet peak load. These resources should be included in the IRP process to ensure that load is being met in a least cost manner.

5. Operational flexibility should be addressed in a detailed operational study.

   To ensure that the portfolio selected is the most reasonable and prudent means for meeting system requirements flexibility needs must be modeled to determine their true costs and benefits.

6. Robust, transparent, stakeholder process.

   A broad array of stakeholders should be included throughout the IRP process with the ability to meaningfully engage.

**Q7. IF YOUR RECOMMENDATIONS ARE ADOPTED, WHAT IMPACT DO YOU EXPECT THEM TO HAVE ON DUKE'S IRP?**

A: In summary, we would expect to see a materially higher volume of solar and storage present as the current IRP process disadvantages these resources through several flawed assumptions and methodologies as outlined in my Testimony.

**Q8. IS IT POSSIBLE FOR DUKE TO ADOPT YOUR RECOMMENDATIONS IN ITS CURRENT IRP?**

A: Yes, there is no reason why Duke couldn't adopt most if not all of my recommendations in its current IRP. The changes I recommend regarding the ELCC calculation assumptions for solar can all be made by Duke during this proceeding. Duke can also revise the way it accounts for resources when calculating its planning reserve margin either by revising its methodology as I recommend, or by "grossing up" the ELCC of solar and storage by the system-wide forced outage rate. Finally, Duke should be required to use a capacity expansion model that is capable of co-optimization across all technology types.

**Q9. HOW IS YOUR TESTIMONY ORGANIZED?**

A: My testimony addresses the following points:

1. Duke has understated the value of solar and storage by modeling their capacity expansion sequentially rather than simultaneously.
2. Duke has erroneously calculated the ELCC for solar and storage.
3. Duke has overstated the capacity contribution of thermal resources in its capacity expansion modeling by assuming they do not suffer from outages.

I conclude with a set of recommendations regarding Duke's calculation of ELCC values and capacity expansion modeling.

## I. DUKE HAS UNDERSTATED THE VALUE OF SOLAR AND STORAGE BY MODELING THEIR CAPACITY EXANSION SEQUENTIALLY RATHER THAN SIMULTANEOUSLY.

**Q10. HOW DO RELIABILITY PLANNING AND RESOURCE ADEQUACY FIT WITHIN THE IRP PROCESS?**

**A:** Ensuring that the electric system is reliable is central to integrated resource planning and reliability planning. When selecting the most reasonable and prudent plan, it is critical that reliability planning and resource adequacy analysis be fully and appropriately incorporated into the IRP modeling process. The standard approach to ensuring reliability is to establish a quantity of generating capacity needed to ensure a given reliability level, usually targeted to be one outage every ten years. This quantity of capacity is characterized through a planning reserve margin (PRM) that specifies the level of generating capacity required in excess of peak demand.

**Q11. WHAT IS THE SIGNIFICANCE OF THE ONE OUTAGE EVERY TEN YEARS STANDARD?**

**A:** The one outage every ten years standard – often referred to as a Loss of Load Expectation of 0.1 or "LOLE 0.1" – is an industry standard metric for reliability planning and resource adequacy analysis. Using this standard, the planner ensures that the utility has enough generation available so that a loss-of-load event is experienced only once every ten years.

**Q12. HAS THE INCREASE IN RENEWABLE ENERGY ON UTILITY SYSTEMS CHANGED HOW RESOURCE ADEQUACY SHOULD BE APPROACHED WITHIN IRP?**

**A:** Yes, the dramatic cost reductions in renewable resources have necessitated a change in the way that utilities should approach resource adequacy within IRP. Some of the tools that utilities used in the past for modeling the capacity credit a given resource could contribute to the utility's load are poorly equipped for measuring the capacity contribution of intermittent resources, because most models and evaluation processes used to perform this analysis were developed during an era when the generation technologies available to utility planners were much more limited than the options available today. Decisions often centered around which type of natural gas generator to invest in or whether a new coal or nuclear baseload unit was required. The objectives of IRP today have evolved from years past and seek to not only minimize cost but also to meet emission reduction or renewable energy goals. Additionally, the types of resources available to planners have also expanded greatly. Techniques that used to provide a reasonable proxy within planning models no longer capture the economic, operational, and reliability complexities of today's resources. IRP must evolve to capture the uniqueness of these resources in order to credibly produce least-cost plans that satisfy both reliability and environmental criteria.

**Q13. PLEASE SUMMARIZE HOW CAPACITY EXPANSION MODELING FITS WITHIN THE IRP PROCESS.**

**A:** Capacity expansion modeling software dynamically evaluates combinations of resources to meet demand across all hours with a pre-defined level of reliability. The approach compares the various resource paths to meeting load and the reliability target in a least-cost manner while achieving any policy goals such as risk reduction, generation diversity, coal retirement guidelines, energy efficiency requirements, etc.

**Q14. CAN YOU PROVIDE AN ANALOGY THAT WOULD HELP EXPLAIN CAPACITY EXPANSION MODELING?**

**A:** Yes. Capacity expansion modeling is like a football coach scrimmaging different combinations of players to determine the best lineup for the season. The coach considers each player's individual strengths in addition to the ways in which the players complement each other. Unlike a football coach, however, capacity expansion software can model thousands of lineups using current and prospective players against various defenses to find which combination performs best over the course of minutes, hours, and years into the future.

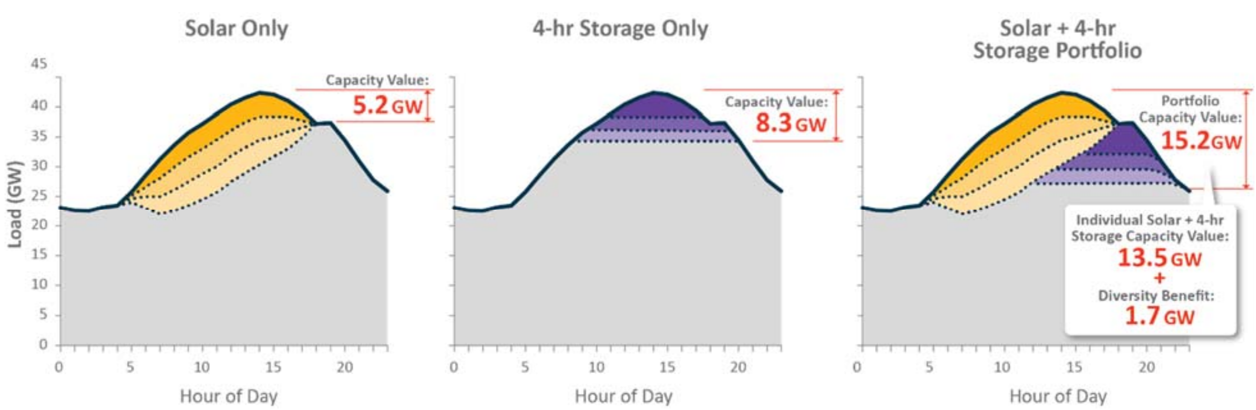
**Q15. DOES THE FOCUS ON COMBINATIONS MEAN THAT INDIVIDUAL RESOURCE CHARACTERISTICS ARE NOT IMPORTANT?**

**A:** Not at all. Just as a coach must objectively understand the size, strength, stamina, and speed of individual players in assigning positions, the capacity expansion modeling must have accurate inputs for individual resources – e.g., capacity, efficiency, fuel costs, ramp rates, outages, etc. – to predict how they will perform.

**Q16. DO SOME RESOURCES' CONTRIBUTION TOWARD RESOURCE ADEQUACY DEPEND ON THE CHARACTERISTICS OF OTHER RESOURCES IN THE PORTFOLIO?**

**A:** Yes. Resources interact with one another, and their combinations can provide capacity contributions greater or smaller than the sum of individual resources. For example, solar and storage have positive interactive benefits – referred to as "diversity benefits" – with daytime solar narrowing the net peak period's duration, which in turn allows energy storage to meet that net peak more effectively. Figure 1 below, which is not specific to Duke, illustrates the point:

**Figure 1: Illustration of the Synergistic Effects of Solar and Storage**




**Q17. PLEASE EXPLAIN FIGURE 1.**

**A:** From left to right, the figure shows the impact on load from solar only, a 4-hour battery only, and solar and storage when combined. Considered separately, solar and storage would have a combined capacity value of 13.5 GW. But if both are added to a system, their combined capacity value is 15.2GW – a 1.7GW (12.6%) increase. This is because of the different ways in which the resources support peak load – solar shifts and narrows the net peak, which is then shorter in duration and can be more effectively met by storage. This interaction is a diversity benefit arising from the interaction of the resources versus other resource additions. However, that benefit will only be apparent in the IRP process if the portfolio optimization including capacity expansion modeling is done to co-optimize all resource technologies, i.e. if all components of the capacity expansion are optimized at the same time, as opposed to sequentially.

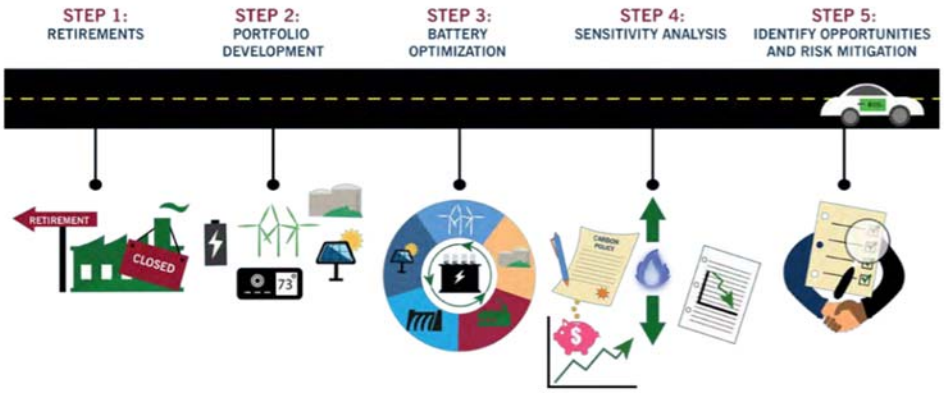
**Q18. MUST SOLAR BE CO-LOCATED WITH STORAGE IN ORDER TO CAPTURE THESE DIVERSITY BENEFITS?**

**A:** No, the diversity benefits arising from the differing natures of the resources, including solar and storage, does not require those resources to be co-located. The same benefits would accrue regardless of whether a solar project was co-located with storage or whether a solar facility and storage facility were sited in different locations.

**Q19. IN CONDUCTING ITS 2020 IRP, DID DUKE CO-OPTIMIZE SOLAR AND STORAGE RESOURCES SIMULTANEOUSLY IN A SINGLE-STEP?**

**A:** No. Duke used multi-step optimization rather than single-step optimization in its IRP. Duke provided the following illustration in its IRP to show its process.

**Figure 2: Visual Representation of the Duke IRP Process**[1]




**Q20. WHAT DOES FIGURE 2 SHOW?**

**A:** This figure and the accompanying text in Duke's IRP indicate that Duke considered firm capacity retirements, renewable additions, and storage additions sequentially. Indeed, Duke states that energy storage was added *after* the optimization was completed so that energy storage would need to *replace* natural gas CT's. This leads to two problems. First, since renewable energy is less valuable without storage, evaluating renewables before storage will result in fewer renewables than is optimal. Second, and relatedly, since storage is most valuable at higher renewable penetrations, the smaller deployment of renewables yields a sub-optimal amount of storage. By failing to accurately capture the synergistic effects of solar and storage, Duke's approach artificially reduced the amount of solar and storage built on the system.

[1] 2020 Duke Energy Progress, LLC and Duke Energy Carolinas, LLC Integrated Resource Plans, Figure A-3.

**Q21. WHAT IS THE SIGNIFICANCE OF THESE MODELING ERRORS ON DUKE'S SELECTION OF THE MOST REASONABLE AND PRUDENT PLAN?**

**A:** Of all of the issues identified in the Report, Duke's use of multi-step optimization rather than single step optimization has the most significant impact on the overall results of their resource adequacy processes. The methodology is such that the diversity benefits of solar and energy storage are not identified and thus any result is going to significantly discount the optimal level solar and storage to build in pursuit of a least-cost portfolio.

**Q22. WHAT STEPS CAN DUKE TAKE TO ADDRESS THIS ISSUE?**

**A:** I recommend that Duke be required to utilize a capacity expansion model that is able to apply single-step optimization. The Duke capacity expansion model should have stand-alone storage, stand-alone solar, and combinations of both as candidate resources when developing portfolio options. This would be a simple fix and would support a co-optimization approach.

**Q23. ARE OTHER UTILITIES ADDING SOLAR AND STORAGE TO MEET CAPACITY NEEDS?**

A: Yes. Three examples of recent IRPs that contain alone solar and storage to meet peak needs are:

- Nevada Energy – In its 2018 IRP NVE announced 1,001 MW of new solar and 100 MW of battery storage to serve both energy and capacity needs.[2]
- Arizona Public Service Electric – APS announced in its September 15th, 2020 IRP Stakeholder Update buildout of 8,000 to 12,000 MW and 5,000 to 10,500 MW of solar and storage respectively to support energy and capacity needs across all IRP scenarios.[3]
- El Paso Electric – EPE announced significant buildout of both stand alone solar and storage through 2037 in its 2018 IRP. The "Most Cost-Effective Portfolio" includes 550 MW of solar and 95 MW of storage.[4]

## II. DUKE HAS ERRONEOUSLY CALCULATED THE ELCC FOR SOLAR AND STORAGE.

**Q24. PLEASE PROVIDE AN OVERVIEW OF THE ELCC METHOD.**

**A:** The historical methodology of determining a resources capacity credit by reducing the nameplate capacity by an outage rate is not applicable for intermittent resources (renewables) and energy limited resources (battery storage). For these technologies the output is based on the weather and the operation of the system respectively. Instead, many utilities, including Duke, have adopted the ELCC method which determines how much

[2] Nevada Energy 2018 IRP, Vol 4 – Summary, available at 18-06003 VOL4: NV Energy IRP SUMMARY.
[3] Arizona Public Service Company, September 15, 2020 Stakeholder Update, available at 2020IRPStakeholderUpdateSeptember152020.ashx (aps.com).
[4] El Paso Electric, 2018 Amended IRP Report, Table 1, available at https://www.epelectric.com/files/Amended-2018-IRP%20Report.pdf.

capacity each resource technology can contribute to peak load on a system based on a statistical analysis of load shape, peak load, generation mix and their correlation with weather.

**Q25. DO YOU AGREE WITH THE USE OF THE ELCC METHOD?**

**A:** Yes, I strongly agree with the use of the ELCC method, which more accurately reflects the capacity contribution provided by renewables and energy storage. Duke should be commended for its use of ELCC, which has not yet been universally adopted by utilities across the country. However, as discussed below in my testimony and attached Report, I have identified a number of flaws in the assumptions that Duke has made in calculating the ELCC values.

**Q26. PLEASE DESCRIBE YOUR CONCERNS WITH DUKE'S CALCULATION OF ELCC VALUES.**

**A:** First, Duke does not utilize an ELCC "surface" for evaluating the ELCC values of different resources. Second, Duke has included a number of assumptions that undervalue the ELCC of solar and of storage resources.

**Q27. WHAT IS AN ELCC "SURFACE"?**

**A:** An ELCC surface is a modeling output that characterizes the ELCC of multiple resources on a given system. The use of ELCC should capture how these values change as the penetration of renewable and energy storage resources change, capturing both diminishing benefits of incremental individual resources and the benefits of combining resources that have complimentary characteristics, like solar and storage. An ELCC surface is the output of this modeling that captures and standardizes these values for use in capacity expansion modeling or other relevant modeling.

**Q28. CAN YOU PROVIDE AN EXAMPLE OF HOW AN ELCC SURFACE WORKS?**

**A:** Yes. An ELCC surface works by representing the combined load carrying capability of resources that are interdependent. As an example, the ELCC of solar is dependent upon the amount of storage on a system and vice versa. The table below represents an ELCC surface for solar and storage resources on an illustrative system.

**Table 1: Illustrative ELCC Surface**

| Combined ELCC Values (MW) | | |
|---|---|---|
| Installed Solar | Installed Storage | Combined ELCC |
| 0 | 0 | 0 |
| 100 | 0 | 50 |
| 100 | 100 | 168 |
| 200 | 100 | 216 |
| 200 | 200 | 312 |
| 300 | 200 | 348 |
| 300 | 300 | 432 |

| Stand Alone ELCC Values (MW) | | | |
|---|---|---|---|
| Installed Solar | Total ELCC | Installed Storage | Total ELCC |
| 0 | 0 | 0 | 0 |
| 100 | 50 | 100 | 90 |
| 200 | 90 | 200 | 170 |
| 300 | 120 | 300 | 240 |

Table 1 shows both the ELCC surface – the combined ELCC values of the solar and storage resources – as well as the stand-alone values for solar and storage individually. As reflected in Table 1, the combined ELCC value of the solar and storage resources is higher than if they are evaluated separately. As an example, 200 MW of both solar and storage on the system has an ELCC of 312 MW while if evaluated separately 200 MW of solar and storage would show 260 MW of ELCC (90 MW of ELCC for solar and 170 MW of ELCC for storage.) The use of an ELCC surface allows for the capacity expansion model to incorporate the dynamic synergies of the resources when added to the system. This is the diversity benefit that has been previously discussed in my testimony.

**Q29. WHAT APPROACH HAS DUKE TAKEN WITH RESPECT TO ELCC VALUES?**

**A:** Rather than utilizing an ELCC surface, Duke uses ELCC curves that vary only based on the amount of installed capacity of the resource in question. This ignores the diversity benefit of the solar and storage being added together.

**Q30. WHAT ARE THE BENEFITS OF COMBINING RESOURCES THAT HAVE COMPLIMENTARY CHARACTERISTICS USING AN ELCC SURFACE?**

**A:** As described above, the contribution of a resource toward system resource adequacy cannot be viewed in isolation and instead depends on the characteristics of the other resources in the portfolio. This is because resources have interactive effects with one another such that a portfolio of resources may provide a capacity contribution that is greater than (or smaller than) the sum of individual resources on their own. To fairly evaluate the capacity contributions of these resources, their diversity benefits must be considered.

**Q31. HAVE YOU CALCULATED THE DIVERSITY BENEFITS OF SOLAR AND STORAGE?**

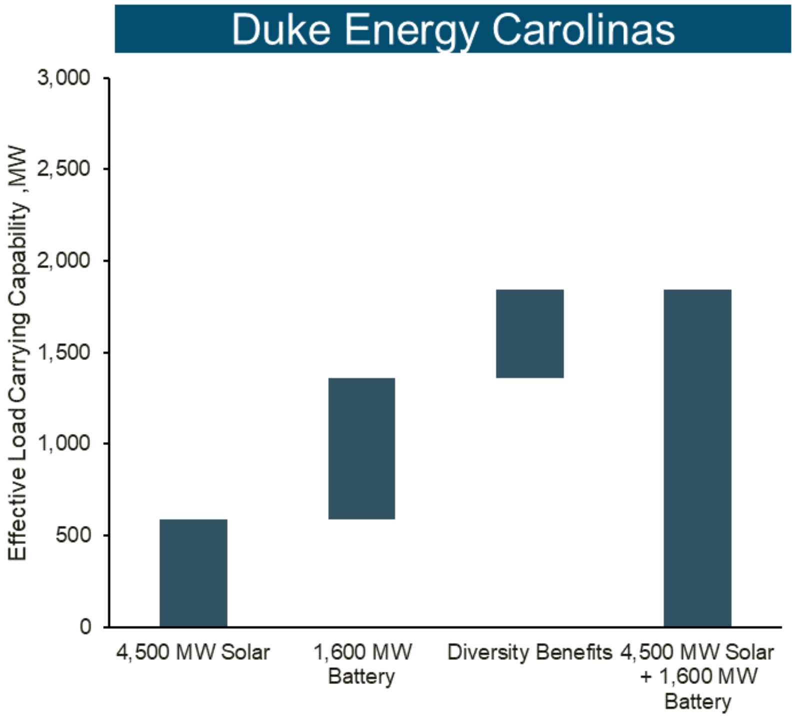
**A:** Yes, using E3's RECAP model, we calculated the ELCC values of solar and of storage on Duke's systems, including a calculation of the diversity benefits when solar and storage are both included on the system.

**Q32. WHAT WERE THE RESULTS OF THAT MODELING?**

**A:** As described in Section 4.2.2 of the Report, when solar and storage are modeled correctly there is a diversity benefit of 25% in DEC and 20% in DEP. This is shown for DEC in Figure 2 below, which depicts the ELCC values of 4,500 MW of solar and 1,600 MW of battery storage. Individually, the ELCC value for the solar is 679 MW and the ELCC value for the storage is 721 MW. Combined, the ELCC value for solar and storage is 1,811 MW.

The diversity benefits of the solar and storage increases the combined ELCC of the solar and the storage from 1,400 MW to 1,811 MW – more than 20% of the total ELCC value.

**Figure 2: Quantification of ELCC and Diversity Benefits from Solar and a 4-hour Storage Device**




**Q33. WILL THE CREATION OF AN ELCC SURFACE ALONE ENSURE THAT ELCC VALUES ARE CORRECTLY INCORPORATED INTO A CAPACITY EXPANSION MODEL?**

**A:** No, as described earlier in my testimony and in the Report, it is critical that properly calculated ELCC values, including use of an ELCC surface, are appropriately applied in a capacity expansion model.

**Q34. WHAT OTHER CONCERNS DO YOU HAVE WITH DUKE'S ELCC CALCULATIONS?**

**A:** Duke used a number of assumptions in its ELCC calculations that have the effect of inappropriately decreasing ELCC values for solar and for storage, including:

a. Not varying ELCC as a function of load;

b. Not updating DR values to include those identified in the Winter Peak Demand Reduction Potential Assessment;

c. Not modeling energy storage resources on a "preserve reliability" basis as opposed to an economic arbitrage basis; and

d. Assuming that only 60% of solar will be tracking.

**Q35. PLEASE DESCRIBE YOUR CONCERN WITH THE CALCULATION OF ELCC INDEPENDENT OF LOAD.**

**A:** The ELCC of a resource is a function of the loads and resources on the system. As more of a resource is added at constant load levels, it effectively provides a larger percentage of total capacity requirements, resulting in a declining ELCC. Conversely, as loads grow, a given resource effective provides a lower percentage of total capacity requirements, resulting in an increasing ELCC. For example, the ELCC of 100 MW of solar on a system of a 15,000 MW peak load will be significantly larger than 100 MW of solar on a smaller but otherwise equivalent system of 1,500 MW peak load.

**Q36. HOW DID DUKE CALCULATE ELCCS WITH REGARD TO LOAD?**

A: Duke calculated solar ELCCs relative to 2020 load levels and storage ELCCs relative to 2024 levels. This approach effectively underestimates the ELCC of solar and storage in years beyond 2020 and 2024, respectively, when load levels will be higher due to growth.

**Q37. WHAT STEPS CAN DUKE TAKE TO ADDRESS THIS ISSUE?**

**A:** Duke should use ELCC values that are dynamic to the system including future load levels. If this is not possible given the modeling software used, Duke should use ELCC values calculated using load levels consistent to the last year in the planning horizon so that procurement is guided by the long-run capacity value of resources.

**Q38. PLEASE DESCRIBE YOUR CONCERN WITH DUKE'S USE OF DEMAND RESPONSE ASSUMPTIONS IN ITS ELCC CALCULATIONS.**

**A:** In its September 1, 2020 IRP filing, Duke included forecasts for the potential of demand response ("DR") programs. These forecasts were used in Duke's ELCC study to calculate ELCC values. In a September 18, 2020 technical briefing, Duke shared an updated forecast for the potential of DR programs. Duke has since published these updated values in its Winter Peak Demand Reduction Potential Assessment (the "Winter Peak Assessment"), which Duke provided in January 2021 in response to intervenor data requests.[5] A copy of the Winter Peak Assessment is attached to my testimony as Exhibit AO-3.

**Q39. HOW DID THE UPDATED DR FORECASTS DIFFER FROM WHAT DUKE FILED IN ITS IRP AND INCORPORATED IN ITS ELCC STUDY?**

---

[5] Ex. AO-3, Duke Response to SCSBA RFP 2 (producing Duke Response to DR Public Staff 5-6), Winter Peak Assessment.

**A:** This updated forecast showed a significant increase in demand response potential in the winter relative to the levels assumed in Duke's ELCC studies. More demand response capacity in the winter would move loss-of-load expectation to the summer, increasing the ELCC of solar. Duke's current ELCC values do not reflect this and should be updated. Specifically, the Duke IRP should include the additional 766 MW and 507 MW of demand potential identified under the Mid Scenario for DEC and DEP, respectively.[6]

**Q40. WHAT STEPS CAN DUKE TAKE TO ADDRESS THIS ISSUE?**

**A:** Duke should update its DR assumptions in its ELCC study to reflect the assumptions it published in its December 2020 Winter Peak Assessment.

**Q41. SHOULD DUKE TAKE OTHER STEPS TO UPDATE ITS ASSUMPTIONS ON SEASONAL LOSS OF LOAD EXPECTATION?**

**A:** E3's analysis did not focus on verifying Duke's assumptions on loss of load expectation or the December 2020 Winter Peak Assessment. However, it is worth noting that a variety of factors could contribute to shifting Duke's loss of load expectation back to summer in a way that would increase the capacity value of solar, including more robust DR program design and utilization, a shift in average weather conditions, and the import of winter morning capacity.

**Q42. DO SOLAR AND STORAGE PROVIDE RELIABILITY BENEFITS ON WINTER PEAKING SYSTEMS?**

---

[6] Winter Peak Assessment – Table 14.

**A:** Yes. It is not accurate to suggest that solar and storage do not provide reliability benefits on winter peaking systems. Solar does tend to have a lower ELCC on systems with loss-of-load expectation weighted toward the winter. However, even a system with a predominantly winter-concentrated loss-of-load expectation generally carries a capacity value for solar. This capacity value is enhanced by the presence of storage, due to the diversity benefits between these two resources. In fact, E3's ELCC modeling described below utilized the same winter-peak presented by Duke. Furthermore, as discussed below, the available storage resources can be operated to maximize system reliability during the very limited days/hours when the system is stressed during the wintertime.

**Q43. PLEASE DESCRIBE YOUR CONCERN WITH DUKE'S MODELING OF STORAGE RESOURCES.**

**A:** Duke has modeled storage in a way that does not capture the maximum value of storage to provide resource adequacy. In the Astrapé Storage ELCC study, three modes of possible storage operation are identified:

1. <u>Preserve reliability mode</u>: where the battery is dispatched strictly to maximize system reliability;
2. <u>Economic arbitrage mode</u>: where the battery is operated in order to maximize the economic value of the battery; and
3. <u>Fixed dispatch mode</u>: where the battery is operated relative to a pre-determined schedule that does not consider real-time system conditions.

**Q44. HOW DO YOU RECOMMEND STORAGE SHOULD BE MODELED WHEN CALCULATING ELCC?**

**A:** I recommend the use of "preserve reliability" mode when incorporating the ELCC of storage into portfolio optimization. Using this mode of dispatch to quantify the ELCC value of storage assumes that storage is strictly operated to maximize system reliability only during the very limited number days/hours per year when the system is stressed and at risk of loss of load – it does not preclude an economic arbitrage mode of operation during all other times. Due to the high value of electricity during loss of load events, a dispatch approach that maximizes reliability is also one that maximizes system economic value.

**Q45. DO SYSTEM OPERATORS HAVE THE ABILITY TO FORECAST SUCH WINTER PEAKING EVENTS IN TIME TO FULLY CHARGE AND DISPATCH BATTERIES?**

**A:** Yes, because these stressful system events are driven by highly forecastable weather events, system operators are able to forecast these events with ample time to charge and hold batteries to discharge when they are needed the most. Therefore, with respect to calculating ELCC for storage, "preserve reliability" mode most accurately reflects system operators' ability to discharge batteries as described above and more appropriately calculates ELCC for storage.

**Q46. WHAT STEPS CAN DUKE TAKE TO ADDRESS THIS ISSUE?**

**A:** Duke can update its ELCC study to model storage resources in preserve reliability mode, including existing pumped hydropower resources.

**Q47. PLEASE DESCRIBE YOUR CONCERN WITH DUKE'S MODELING OF FIXED-TILT VS. TRACKING SOLAR.**

**A:** Solar projects can be either fixed-tilt or tracking. Fixed-tilt solar arrays remain fixed, whereas tracking solar arrays move throughout the day to maximize exposure to solar radiation. As a result, a MW of tracking solar generally generates more electricity than a MW of fixed-tilt solar. Tracking systems also tend to have higher production during the late afternoon when loss-of-load events are most likely to occur. In its Solar ELCC Study, Astrapé assumes that 40% of future solar is fixed-tilt and that 60% of future solar is single axis tracking.

**Q48. IS THIS ASSUMPTION APPROPRIATE?**

**A:** No. Technological advancements and cost decreases in tracking systems for solar plants has resulted in an increasing dominance of tracking systems, to the point where very few fixed tilt systems are being installed.[7] Furthermore, decreasing costs of tracking devices has resulted in the 2018 installed price of solar being roughly equal for fixed-tilt and tracking projects at \$1.40/$W_{AC}$ and \$1.46/$W_{AC}$ respectively.[8] Therefore it is highly likely that new solar projects constructed in Duke's South Carolina and North Carolina service territories will use tracking systems rather than fixed-tilt systems. Given the price parity and the clear industry shift to tracking, I recommend that the marginal ELCC of solar be based on 100% tracking solar for new installations.

**Q49. DID E3 CALCULATE REVISED ELCC VALUES FOR SOLAR AND STORAGE AFTER CORRECTING FOR THESE FLAWS?**

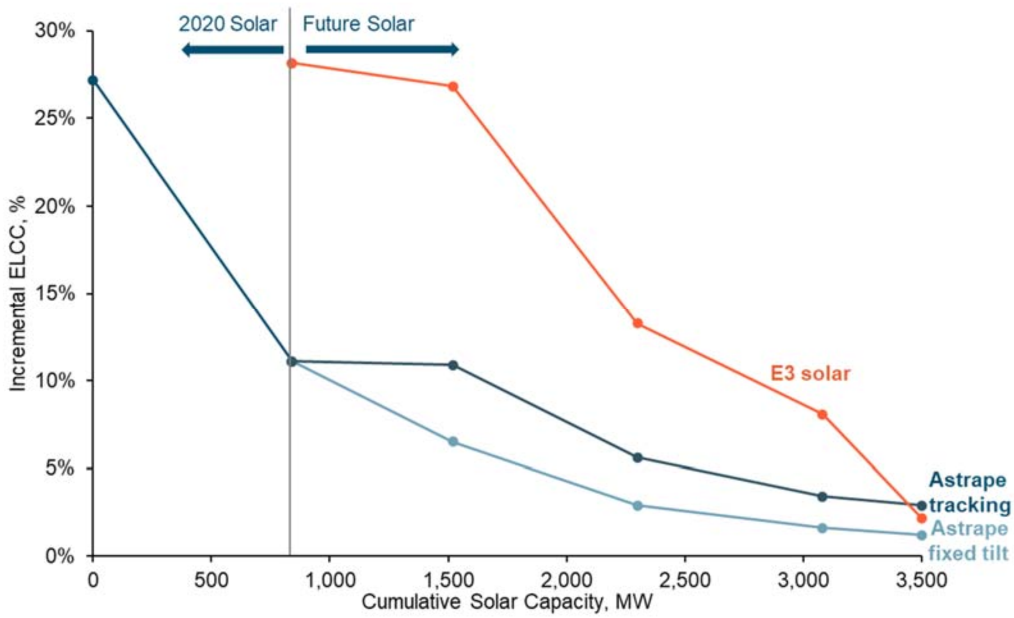
---

[7] See, Report – Section 4.1.5.

[8] Berkeley National Lab and Energy Information Administration. Utility Scale Solar Data Update: 2020 Edition.

**A:** Yes, E3 used its RECAP model to calculate ELCC values for DEC and DEP, shown in Figure 3 below.

**Figure 3: E3 Modeling of Solar ELCC on the Duke Energy Carolina's System**




As shown, the initial E3 ELCC values of solar are significantly higher than Astrapé values, with the ultimate results converging at higher penetrations around 3,500 MW. Based on the modeling performed by E3, it is not possible to allocate the differences to each individual recommendation as they are modeled as a package. However, it is accurate to say that all of the recommendations made by E3 would have the effect of increasing the solar ELCC values compared to the Astrapé study.

The DEP system was also modeled using RECAP and, given the significant amounts of solar and limited storage on the system, there were no material differences between the E3 modeled values and the values used in the Duke IRP.

## III. DUKE HAS OVERSTATED THE CAPACITY CONTRIBUTION OF THERMAL RESOURCES IN ITS CAPACITY EXPANSION MODELING BY ASSUMING THEY DO NOT SUFFER FROM OUTAGES.

**Q50. PLEASE DESCRIBE YOUR CONCERN WITH DUKE'S ACCOUNTING PRACTICES IN THEIR PLANNING RESERVE MARGIN CALCULATION.**

**A:** As I describe in more detail below, Duke has used an approach to its planning reserve margin ("PRM") modeling that overvalues firm resources like coal and natural gas relative to intermittent resources, namely solar and storage. Duke uses a PRM calculation method called "installed capacity" planning reserve margin or "ICAP PRM". The ICAP PRM has historically been used by utilities to calculate reserve margins, but it does not compare firm and intermittent resources on an even playing field, and as a result, it overvalues firm resources and undervalues intermittent resources. To correct this error, I recommend that Duke use a different accounting practice to calculate PRM—the "unforced capacity PRM" or "UCAP PRM"—which will ensure that firm resources and intermittent resources are accounted for consistently and therefore accurately modeled on Duke's system.

**Q51. CAN YOU EXPLAIN HOW PLANNING RESERVE MARGINS ARE CALCULATED?**

**A:** The standard approach to ensuring system reliability is to establish a quantity of generating capacity needed to ensure a given reliability level, usually targeted to be one outage every ten years. This quantity of capacity is characterized through a PRM that specifies the level of generating capacity required in excess of peak demand. In other words, a PRM is calculated by identifying the utility's peak demand and determining how much additional reserve capacity the utility should hold to ensure a specified level of reliability (e.g., one loss of load event in ten years). Once the PRM is established, the utility can model different combinations of resources to meet the desired reserve margin.

**Q52. HAS PRM ACCOUNTING CHANGED AS RENEWABLES HAVE BECOME MORE PREVELANT?**

**A:** In the past, PRM accounting was relatively simple because most generating capacity was "firm" – available at full capacity except in the event of forced outages. However, with the growth of intermittent capacity, namely renewables, the nature of reliability planning is changing. Increasingly, the industry has turned to ELCC as the preferred method for measuring the resource adequacy contribution of intermittent or dispatch-limited resources. Duke has adopted the ELCC approach for renewables, which I support. The problem, however, is that Duke continues to use its existing ICAP PRM method, which is incompatible with ELCC and undervalues intermittent resources in comparison to firm resources. The UCAP PRM method, which more consistently accounts for both firm and intermittent resources, would be a more appropriate method.

**Q53. HOW DOES THE ICAP PRM METHOD DIFFER FROM THE UCAP METHOD?**

**A:** The ICAP PRM model assumes that all firm resources are available at their full nameplate capacity, it does not account for forced outage rates (i.e. unplanned outages). For example, under ICAP, a coal unit with 500 MW nameplate capacity and a 5% forced outage rate would be given a capacity value contribution to the ICAP PRM of 500 MW.

In contrast, a UCAP PRM model incorporates assumptions regarding forced outage rates for all generating assets. For example, the same 500 MW coal unit with a 5% forced outage rate, would result in a capacity value contribution of 475 MW to the UCAP PRM (or 95% of nameplate). There is no physical difference to the system size or the generating units between the ICAP or UCAP method – the difference is simply how the PRM, and available resources to meet it, are calculated and accounted for.

**Q54. DOES ELCC ALIGN WITH ICAP OR UCAP PLANNING RESERVE MARGINS?**

**A:** The use of ELCC to value the capacity credit of intermittent resources is directly aligned with the UCAP PRM accounting method. By definition, ELCC derates the nameplate capacity of a resource to account for times when it is unable to generate electricity and represent the amount of that resource that can support peak load. This is the same process that is applied to the coal plant under the UCAP PRM accounting method in the previous question.

As indicated in Figure 4 below, for Duke to use ELCC values and compare resources' capacity contribution to peak load on an apples-to-apples basis, it must use the UCAP PRM accounting methodology.

**Figure 4. Illustration of ICAP and UCAP Accounting**

| | **Thermal Generation** | **Solar** | **Storage** | **Comparison** |
|---|---|---|---|---|
| **ICAP** | Nameplate Capacity (Full Rating) | ELCC (Derated) | ELCC (Derated) | Unlevel |
| **UCAP** | Derated Capacity (forced outage rate) | ELCC (Derated) | ELCC (Derated) | Level |

**Q55. WHY DOES THE ICAP PRM METHOD UNDERVALUE INTERMITTENT RESOURCES LIKE SOLAR?**

**A:** Duke uses ELCC to determine the capacity contribution of intermittent resources. ELCC is much more aligned with UCAP than it is with ICAP in that ELCC discounts resources for expected availability during peak periods. But because Duke uses ELCC values in an ICAP PRM intermittent resources are discounted, whereas the firm resources are not discounted. As a result, the model gives discounted credit to non-firm resources that use ELCC and full credit to firm resources modeled with ICAP.

**Q56. WHAT STEPS CAN DUKE TAKE TO CORRECT THIS ISSUE?**

**A:** Duke should apply the UCAP PRM accounting in its IRP. More specifically, Duke should credit thermal resources at a capacity contribution that reflects their forced outage rates.

## IV. RECOMMENDATIONS AND CONCLUSION

**Q57. PLEASE PROVIDE YOUR RECOMMENDATIONS REGARDING DUKE'S CALCULATION OF ELCC VALUES AND CAPACITY EXPANSION MODELING.**

**A**: I recommend that Duke make a number of changes to its development of effective load carrying capability ("ELCC") values and revisions to its capacity expansion modeling that incorporates those ELCC values, including:

1. Applying single step optimization rather than multi-step optimization when conducting its capacity expansion modeling;
2. Creating an ELCC "surface" that determines the combined capacity value of different portfolios of solar and storage;
3. Revising their 2018 ELCC study by:
    a. Varying ELCC as a function of load, including applying a 2040 load profile;
    b. Updating DR values to include those identified in the Winter Peak Demand Reduction Potential Assessment;

c. Modeling energy storage resources on a "preserve reliability" basis as opposed to an economic arbitrage basis; and

d. Changing future solar technology assumptions from 60% tracking to 100% tracking.

4. Applying the UCAP rather than the ICAP PRM method so that the forced outages of solar and thermal resources are considered on a level playing field.

**Q58. DOES THIS CONCLUDE YOUR TESTIMONY?**

**A:** Yes, it does.

**DIRECT TESTIMONY OF ARNE OLSON
ON BEHALF OF
THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE**

# EXHIBIT AO-1

Docket Nos. 2019-224-E
and 2019-225-E

**DIRECT TESTIMONY OF ARNE OLSON**
**ON BEHALF OF**
**THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE**

# EXHIBIT AO-2

**DIRECT TESTIMONY OF ARNE OLSON
ON BEHALF OF
THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE**

# EXHIBIT AO-3